COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
INFORMATIONAL PROCEEDINGS AND	)	Docket No.
PREPARATION OF THE 2003	)	02-IEP-01
INTEGRATED ENERGY POLICY REPORT	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 10, 2003

Reported by:
Alan Meade
Contract No. 150-01-005

COMMISSIONERS PRESENT

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William J. Keese, Associate Member

STAFF PRESENT

Al Alvarado

Judy Grau

Melissa Jones

David Vidaver

Karen Griffin

OTHERS PRESENT

Morteza Sabet

Chris Bing

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Devra Bachrach

Mark Hesters

I N D E X

P R O C E E D I N G S

9:35 a.m.

PRESIDING MEMBER BOYD: Good morning, everybody.

AUDIENCE: Good morning.

PRESIDING MEMBER BOYD: That's what I like, an audience that talks back. That's the idea. Well, welcome to what some of us are forced to say is yet another in the continuing series of workshops that we have been having, and will be holding more of this month in support of the California Energy Commission's Integrated Energy Policy Report.

I'm Commissioner Jim Boyd. I'm the Presiding Member of the Committee that was created to be responsible for this report. And I'm joined by the second member of the Committee, Commission Chairman Keese.

The Committee was established by the Commission to, as I said, oversee the development of this report to preside at various proceedings like this, which report was required by Senate Bill 1389, past by the legislature, signed by the Governor.

The legislature has often repeated

that's their responsibility of state government to ensure reliable supply of energy to see that it is maintained at levels consistent with the needs to protect the public health, safety, welfare, and environmental quality in this state, as well as to support the California economy.

The so called Integrated Energy Policy Report is designed to identify merging trends related to energy supply, demand, price, conservation and efficiency majors, and public health and safety issues. And ultimately to provide a basis for state policy and state actions.

The Energy Commissioner is required to submit this report to the Governor and legislature by November of this year, and to update it and submit a report every two years thereafter. As I indicated, we are conducting, have, and will continue to conduct a number of public policy workshops on different energy related subjects that we are considering in preparation of the, as call it, IEPR.

The purpose of the workshops is of course to receive public comments and technical feedback to establish a factual record, and to inform the committee and ultimately the Commission on the relative and the necessary energy policy choices.

We've already discussed in previous workshops were loyal issues, electricity efficiency opportunities, hydropower system, and environmental concerns, air missions, public health considerations, all of which are associated with energy use here in the State of California.

Today's workshop, and tomorrow's workshop, are focused on potential electricity and natural gas infrastructure concerns that California may need to address throughout the rest of -- at least throughout the rest of this decade.

Senate Bill 1389 specifically calls for an assessment of the electricity and natural gas system, which includes the consideration of many different system elements ranging from demand trends, transmission developments, and regional market implications, certainly events of the last three or more years have exposed extreme vulnerabilities of the state's electricities and natural gas system.

And are a deep concern to many agencies, in particular this agency. This committee believes the most pressing issue is whether these vulnerabilities are still a concern or whether administrative, legislative, regulatory and private sector actions, in response to recent events, have addressed the vulnerabilities, at least for now.

To address this issue, the Committee believes we need a better understanding of the state's energy infrastructure, because strong energy infrastructure is paramount to California's economic and environmental future.

Having said all this, I would like to first turn to Chairman Keese for any comments he'd like to make, and then turn to the staff to hear about the findings of their recent studies and efforts. And Al Alvarado, staff, will provide an overview of the workshop immediately following Commissioner Keese's comments.

CHAIRMAN KEESE: I'll reiterate a comment that I've made at a number of the previous events that we've had, which is we start with the assessment, and that will be by staff and the participants here in the room. But we end up with the recommendations we will be making to the Governor for state energy policy.

And that's what we seek your input on, what recommendations should we wind up with at the end? We have to agree on the assessment, uniformed assessment. All of us seeing electricity and natural gas the same way would be really helpful. But then the important thing is what are those recommendations?

And to the extent that you can help us out by crafting the recommendations that you should think we should be considering, we would appreciate it.

PRESIDING MEMBER BOYD: Mr. Alvarado.

MR. ALVARADO: Good morning. My name is Al Alvarado. I'm the project manager for the electricity and natural gas report. This is one of three subsidiary reports that are being prepared to support the Integrated Energy Policy Report.

So the purpose of today's workshop is to discuss and receive comments on the findings of the staff, electricity infrastructure assessment report that was posted on the Commission's website on May 27th. The analysis that is presented in this staff report will build on the five staff draft reports that were released back in February.

And was the subject of a previous IPR workshop. Staff has updated the assumptions used in the infrastructure analysis based on the public comments we had received from this workshop. The staff energy system studies evaluate the implications of a number of important uncertainties on the integrated electricity and infrastructure.

The primary goal is identify factors that may stress the energy infrastructure, and determine if there's need for any additional development to mitigate potential supply shortfalls over the next decade. Considering that electricity generation is a primary energy sector that may have the largest on future natural gas demand, the energy infrastructure study is focused on potential stresses to the natural gas fuel system.

Tomorrow's workshop will cover the findings on the natural gas system studies. The discussion and technical feedback that we receive at today's workshop, and during the next several events, as Commissioner Boyd had pointed out, we have a whole series of different workshops this month.

And there is a list of the other events up at the front desk. The discussions and the comments we receive will serve to refine the staff energy system studies, and also in the preparation of the draft electricity natural gas report. This electricity natural gas report is targeted to be released for public review on July 25th.

And as Commissioner Boyd pointed out, the tentacle analysis as included in this report will provide the findings to support any development of policy recommendations that the Committee may consider for the final Integrated Energy Policy Report.

So we are interested in hearing from you, your views and your perspectives on today's subject matter. We will be transcribing this workshop to help us track all of your comments. So this will require you, if you have any comments, at least come to the front desk, a microphone over here, and identify yourself.

And please provide a business card to our court recorder. This will help us keep track of who you are in our transcripts. Again, the purpose here is hear from you. So hopefully we can have a rather lively discussion.

Today we're going to have two staff members that's going to provide an overview of the basic assumptions and the findings that are contained in this report. We have David Vidaver who's in our electricity analysis office and has been responsible for conducting most of our electricity system studies.

And we also have Judy Grau from our engineering office who will cover related transmission issues. So with that being said, I think I'll turn to David.

MR. VIDAVER: Good morning. How close do I have to get to this damn thing? Okay. Good luck. I'm going to fade in and out.

PRESIDING MEMBER BOYD: David has been described an eight-inch cone of acceptability in front of this microphone.

MR. VIDAVER: Okay. Sorry, wrong copy I think. Sorry. The only people who weren't laughing were the lawyers who going what's funny about that? I was asked to make this pretty simple. So as Al said, I'm going to discuss generation adequacy.

Judy Grau will follow me and discuss transmission issues. So this is as simple as it gets. Current market conditions, which we're all pretty much in agreement about. Projections for 2004/2006, which Commission staff is somewhat confident about. But you're welcome to take potshots. I'm sure you will.

And then concerns for 2007, which is choose apocolyptics and aria. Let's see here, so this give the illusion of simplicity. It will probably be a little more challenging than that. Current market conditions, this is a graph of spot market prices, both electricity spot market prices and natural gas spot market prices over the last two years.

For those of you who can't see the screen, natural gas is at the top. Peak and off peak prices at the bottom. These are monthly averages taken from economic inside and NGI. They're unrated. So if they're off, please accept my apologies.

The left hand access is dollars per megawatt hour. The right hand access is dollars per MMBTU, a little diversion. The question is often asked who cares about spot market prices? We at the point we're procuring 95, 98 percentage of energy forward. And the spot market prices may or may not have any real relevance.

While some may disagree, it's the contention of staff that spot market prices do serve as bench marks for not only short-term contracts, but long-term contracts as well, hedging decisions. And most importantly, the decision to build new capacity.

There are those who would claim that new capacity decisions are simply a function of whether or not you'll have a long-term contract for your output. And well it may be true at the moment, very few new plants are going forward without long-term contracts.

This would arguably be subject to change. It's spot market prices all of a sudden peaked for one reason or another. As you can see from the graphs, spot market prices are tracking the natural gas price at an implied heat rate that reflects competition.

Spot markets have been competitive since July of 2001 for a couple of reasons. One is that we've added net 7,000 megawatts of capacity in state. Similar figures exist for the northwest and the southwest. And consequently, we have a capacity surplus. In addition, we've stopped procuring energy in the spot market for the most part.

This is having an effect on spot market prices and more and more megawatts of capacity or chasing fewer and fewer megawatt hours of demand. We have had a large number of cancellations. There are a lot of new plants that haven't gone forward.

I'm not sure that the significance of this has not been overstated. I read the other day that of 110,000 megawatts of proposed additions in the WECC. 80,000 megawatts of those have been canceled. And this is a sign we're in trouble.

And all could think was, well, we're really lucky that 210,000 megawatts weren't announced and 180,000 weren't canceled, because we'd all probably be sitting in the dark. Regarding reliability, we've had two events in the last two years of significance, which people indicate that we face present reliability problems at a regional sense.

July 10th, of 2002 a stage I emergency was declared. At that time, temperatures in Northern California were, I believe, at one and 15 years highs. Similar temperatures were observed in the northwest. The transfer capability on major transmission path from the northwest was reduced for a number of reasons.

A large number of units were out on force maintenance, coincidentally the price cap had been lowered down to $55 the previous day. And as result, there was not a lot of capacity in the market. We ended up, the ISO ended up, declaring a stage I at which point, I think, 14 or 1,500 megawatts of inter-roundables were called, and the situation resolved itself.

The only reason it was necessary to call a stage one is the interruptables couldn't be called until an emergency had been declared. So in fact, despite all the adverse conditions, we were really never in danger of having lights go out.

So that should take care of concerns regarding 2002. We also have on the 28th, of May of this year, a couple weeks ago, the stage I was declared again. But this occurred largely as a result of the ISO and everyone else failing to forecast the temperature spike.

And had the ISO forecast temperatures

accurately, there would not have been 11,000 megawatts of capacity out on economic outages. And arguably there wouldn't have been 3,200 megawatts of planned maintenance at the time.

So contrary to what was reported in the press, the events of the 28th, are not really a sign of things to come. But we do appreciate they're encouraging everyone to continue to conserve. So, let's see, projective 2004 to 2006 conditions, these numbers are all in megawatts.

They're all dependable. I was asked to reduce the numbers on this chart. So of course I removed the headers, the first column refers to 2004. The second to 2005, and the third to 2006. These are statewide numbers. They're dependable capacity.

The Commission has been accused occasionally of using name plate capacity or some other inappropriate indicator of how much capacity is available in this state. The expected available generation includes such things as a hydro D-rate to account for the possibility of a (indiscernible) water year.

It includes forced outages assumptions that are quite conservative. We assume, I believe it's 3,750 megawatts will be forced out on peak on average. We attribute 2,750 megawatts to the ISO control area. When in fact, in 2002 the average number of megawatts down in the ISO during the summer was about 2,100.

So we're deliberately conservative. The net additions reflect our assumptions regarding the addition and retirement of capacity. We assume at 4,400 megawatts of capacity will be added, 2,800 megawatts of capacity will be retired over the next three years.

We're going to go into those numbers in more detail. The resulting operating reserves between 14 and 17 percent over the next three years indicate that even under adverse weather conditions we should not have to turn the lights out. These numbers all assume that capacity will be available to California load-serving entities.

It's been stated that this is apt to be wrong, that some capacity, perhaps a large quantity, maybe contracted to load-serving energies out of state. We admit that we don't have an adequate amount of information in this regard. Generators are not required to inform us, or anyone else, of any contractual obligations that they have, not only out state, even in state.

However, the rather large surpluses that exist in the northwest and southwest today would seem to indicate that it's unlikely, even on peak, a large amount of capacity in California will be committed elsewhere. I should return the expected available generation number and say we're also assuming the availability of 2,700 megawatts of spot market imports.

This number is based historical analysis. This roughly the same amount of energy that California was able to obtain from the northwest and southwest on peak in 1998 and 1999. Certainly the transfer capabilities of the grid are the same. And there is more surplus available from the northwest and southwest than was the case in 1998 and 1999.

These regions have added a large amount of capacity. We've published those numbers elsewhere. Loads in the northwest continue to remain at early and mid 1990s levels largely due to the demise of the aluminum industry. Six percent of the northwest loads have all but disappeared.

The additions and retirements that we

assume in 2004 through 2006, these are conjectures. We assume that 4,300 megawatts of dependable capacity will be added over the next three years. 3,100 of this consists of projects that have been proposed or are under construction by load-serving energies in the State of California.

They are going to be used to mitigate exposure to the spot market, to replace existing facilities that will be retired, and to replace contracts that are due to expire. Because these projects are being put forth by load-serving entities, we assume that they will be built.

We assume only two merchant projects will go forward in the next three years. In our studies we assume that those projects are Metcalf and Otay Mesa. However, the results of our analysis don't fundamentally change if you assume it's two other projects of equal size.

And there are several projects, which could be on line by 2005, notably Mountain View, Palomar. Staff acknowledges that there are liquidity problems. It says we were getting merchant plants on line, and the low forward prices would seem to a addition to bringing plans forward.

But if those who are predicting an apocalypse are correct, and that 8,000 megawatts of capacity will be retired over the next two years, or some other large numbers, loads will increase and we will have a crisis by 2005 or 2006. It would seem logical one or two of these merchant plans might wake up and smell the coffee and finish construction.

The retirements that we assume 2004 to 2006 are primarily plants which will -- I'm losing my train of thought. I'm sorry. The retirements that we assume in 2004, '05 and '06 are primarily plans which have attentions to retire. Many of them would be replaced by Repowers, Valley and Haynes for LADWP.

We assume Hunters Point will be retired at the end of 2005. We have already retired a large number of facilities that are shut down due to the need to add emissions controls, which owners have felt were not cost effective given anticipated forward prices.

So much of the retirements that are apt to occur, due to tightened emissions constraints, have already taken place as far as we're concerned. They are not reflected in these numbers because we assume they retired at the end of 2002 or in early 2003. This is about 1,700 megawatts of capacity.

1,200 megawatts largely due to rule 2009 and the south coast air base, some capacity in San Diego, which is leased with the US Navy. We assume for example that Pittsburgh Three and Four are already retired. They're not reflected in these numbers. I'll return to retirements in more detail because they do reflect a risk that the state faces during the coming two or three years.

The high reserve margins that we anticipate will prevail during the next three years, minimize the likelihood of shortages, of reliability concerns. And it says here the price spikes. By the time the day market opens load-serving energies will have secured energy and capacity to meet a lion's share of their load.

The exact percentage is going to depend on activity, future activity and the PUC's procurement proceeding. Reduced reliance on the spot market means that large quantities of capacity are chasing a relatively small amount of demand. This has been cited as primary reason for competitive spot market as of July 2001 in California.

And staff feels that these conditions will continue to prevail. Generators no longer have incentive to withhold capacity from the market, nor do they have the ability to offer energy at values substantially in excess of their cost of generation. As I mentioned, substantial surplus is in neighboring states.

It reduce the demand for California exports. Meaning that more capacity in California will be bidding for California loads. Our simulation analysis indicate that under the assumptions that we made regarding additions and retirements, no unserved energy is expected in California, or on peak, except perhaps in San Francisco in 2004 prior to the expansion of the Jefferson-Martin line and a greater import capability, and the addition of 180 megawatts at peaking facilities that are expected to be added in San Francisco in 2005.

One caveat, a competitively priced spot market doesn't necessary mean that prices are going to be low by historical standards. Prices will continue to be driven by spot prices for natural gas. As gas prices apt to be high throughout the remainder of the year, storage is increasing -- excuse me, competing with consumption.

You're all familiar with current issues on the natural gas market. Failure to inject an adequate amount of gas into storage could lead to higher winter prices. As recounts, you're increasing. It's expected that prices are going to fall next year, but nothing is certain. In my mind, even less as certain because I don't know a whole lot about this. The gas unit is going to talk tomorrow.

Staff's conclusions regarding conditions in 2004 and '06 are predicated on load serving energies continuing to hedge exposure in the spot market during the next couple of years. For the IOU's this simply means approval by the PUC of necessary four contracts, including those that would replace expiring contracts, either DWR contracts or QF contracts.

Municipal utilities are soon to continue to minimize exposure to the spot market using both existing and new capacity, and forward contracts to do so. In addition, staff assumes that existing access providers will not rely excessively on a spot market to meet obligations.

These providers are assumed to prudently manage their risks, required to do so is necessary by legislation or statute. That the direct access providers presently are in a position where they don't necessarily have to prudently manage risks.

This is an issue of concern for the investor of utilities who may, under some scenarios, be faced with the task of suddenly serving loads for direct access. So we assume that this is not going to be the case, that you won't suddenly have two or three megawatts of demand appear in the spot market.

The primary risk, we feel is being faced ratepayers is the risk of high natural gas prices. Ratepayers are exposed to this risk through spot market purchases, QF contracts, index to gas, dispatchable DWR contracts. There is one must take DWR contract that's index to gas, and all short-term contracts.

Those are six months or less. High natural gas prices can result from transient weather conditions, for example an arctic cold snap, dry hydro conditions, or other seasonal weather patterns, which went in storage. These risks could be hedged to some extent.

It's our understanding that investor owed utilities are seeking to do this through the procurement proceeding at the PUC. We assume that the PUC will allow them to continue to do this as long as it's in the interest of ratepayers. We also assume that municipal utilities hedge their gas price risk.

So returning to retirements, staff feels that several factors should limit retirements during the next three years. Well, the subsequent -- a substantial share of the state's generation fleet is old and due to retirement. We also note that information needed to access the likelihood of retirements is confidential, and often subjective.

Staff is not well positioned to analyze the likelihood of retirement on a case by case basis. That being said, we believe there's several reasons we'll see capacity stick around for two or three years. One is the RMR contracts, a small share of the state's agent capacity is actually obligated to provide energy capacity under a long-term RMR contract -- excuse me, the

DWR contract.

RMR contracts are keeping generation in San Diego afloat. A substantial amount of generation in San Francisco as well, and a small amount of generation in the south coast. The need for capacity on the part of load-serving entities we feel is going to encourage some generators to stick around, as long as the PUC continues to allow the IOUs to hedge price risk by contracting forward.

We feel that a substantial amount of capacity is going to stick around. And finally, the substantial uncertainty regarding the development of new capacity over the next two three years, as well as uncertainty regarding transmission upgrades, is going to result in plants sticking around.

The decision to retire is irreversible. Once you dismantle your plant you can't change your mind. It was forecast in 2001 that by 2003 a large portion of the state's fleet would be gone. We argued at that time that it would continue to stick around due to various uncertainties, including regulatory uncertainty.

We don't feel that that situation has

substantially changed. That being said, there are several large plants in California which are faced with the obligation to install emission controls. Their risk is on the slide. It's actually quite a short risk. A large share of the plants that have been faced with this decision have already made it.

They're either still in operation or they've been retired. The plants, two of the plants listed, Pittsburg 7 and Contra Costa 6 are in a rather unique position. The ISO reported last week that its RMR requirements for the San Francisco Bay Area are apt to drop substantially from 7,800 to 3,600 megawatts.

This is going to make it very difficult for Pittsburg 7 and Contra Costa 6 to provide competitive bids for RMR services if they expect to recover the cost of installing emissions controls. As this is something that we've just been faced with within the last week, we're not really in a position to evaluate the likelihood that Pittsburg 7 and Contra Costa 6 will have the incentives to retirement.

It should be noted that they both operated a substantial number of hours in 2002, the extent of which that will be the case in 2004, 2005, and 2006 is questionable. Our simulation show that from the perspective of the market there needed less and less. If they're not needed from a reliability prospective, and do not procure more contracts, it's a possibility that they would have incentives to retire.

Okay. Now, that we've painted such a rosy picture, albeit with a great deal of uncertainty, it appears as though spot market prices in 2004 through '06, while competitive, are not apt to provide incentives for new capacity. The resulting sparks spread are quite low.

This should not be taken to mean that individual developers may not have more optimistic outlooks. The decision to bring a plan on line in 2005 is less dependent on one's forecast for prices in 2005 than it is for prices in 2006, '07, '08, '09, '10.

If individual developers perceive that the rather apocalyptic predictions of some analysts are apt to be borne out, staff believes that these plants would simply come on line. Give the current surplus, load-serving entities may not have incentives to forward contract for all the peak load.

Prudent portfolio management arguably will dictate for a load-serving energy to rely on the spot market for its last few percentage of load when it feels that spot market prices are going to be reasonably low and stable. Given that that's the forecast for the next couple of years, we would expect that load-serving entities will, if not lean on the spot market a little bit, they will certainly rely on very, very short-term contracts for a share of their load.

As such, there's little incentive for new capacity based on the short-term contracts. The addition of capacity is encourage by allowing load-serving entities to enter into long-term contracts. We assume that the PUC will do that as part of the long-term procurement proceedings and the long-term plans being submitted by the utilities.

However, in the current market there is an excess amount of base load capacity. This was acknowledged by PG&E in their long-term filing. They believe they have an adequate amount of -- there is an adequate amount of base load generation in the state through the end of the decade.

The problem is peaking capacity. As long as you anticipate stable and reasonably low spot prices there's really no incentive to go out and sign capacity contracts, contracts for peaking capacity that might incent new peaking generation.

So what this is all intended to say is that, even if load-serving entities go forward and sign long-term contracts to the extent that it's prudent to do so, there is no guarantee that allowing utilities to engage in prudent portfolio management is necessarily going to lead to a reliable electricity system.

There's no guarantee that even in this environment the market is going to cough up and adequate amount of peaking capacity in a timely fashion. So one thing that could ensure that are rather stringent resource adequacy requirements.

Those are being discussed in Washington. They're being considered here in California. There is of course that tradeoff between a resource adequacy requirement that requires ensuring sufficient capacity to keep the lights on, and reducing the amount of flexibility that both serving entities have to meet load in a cost efficient fashion.

In other words, to take advantage of, for example, demand site programs that might serve us. So the upshot of these less than novel observations is that the state will have to continue to monitor the market to ensure that an adequate amount of capacity is available, and to allow utilities to offer incentives for new capacity when it's deemed necessary.

We simply can't get away from the fact that information is a paramount concern and that there is a fine line between requiring the addition of new capacity when it may not be necessary. And assuming that the market will provide when it in fact may not.

Our final concern relates to local area reliability. San Francisco and San Diego illustrate that under certain circumstances regulators may have to, and I use the word here "compel", solutions to local reliability problems. I'm going to use the less sensitive example of San Francisco.

It appears as though between the expansion of the Jefferson-Martin line and San Francisco's intention to add peaking capacity that local reliability problems in San Francisco have been forestalled for let's say five years. But in the even that Jefferson-Martin were not built, in the event that Hunters Point were to be shut down due to local concerns, we'd be facing a very serious problem, and that is you would not be able to meet local reliability criteria in San Francisco.

That being the case, it would be incumbent upon the regulator community to prescribe a solution. To date the regulators have avoided doing that, allowing San Francisco to come up with a solution which met local concerns. This appears to have been successful.

San Francisco will no doubt go forth with energy efficiency programs, demands on management program, and generation options, which will meet its concern for the environment, and environmental justice. However, this is not a necessary outcome.

It's possible that at certain times and certain places that the state would be in a position where it would have to literally compel a certain solution in order to keep the lights on. And that is something that has to be kept in mind.

Staff simulated the market under a set of assumptions for 2007, 2013. It did so in large part to provide input and other analysis being done by the Commission, analysis related to emissions, gas use, etcetera. As was stated in the report, this is not a forecast. This does not assume that the state and the market together will ensure an adequate amount of capacity.

It was just simply a logical baseline from which to analyze the effects of other policies. To assume that the market would fail and the state would be unable to do anything about it did not seem to be a prudent basis for planning an analysis.

The assumptions regarding the additions in retirements we used in these scenarios are stated elsewhere in the report. We added renewable resources needed to meet RPS targets. We assumed continued funding in efficiency programs at comp levels.

And we came up with spot prices in the 36 to $49 range treading upward due to the eradication of the regional capacity surplus that we anticipate will exist in 2006 will be gone in about 2008, 2009. And we also assume that natural gas prices continue to rise, I believe two percent real.

But that could be slightly off. One thing that comes out of this is even with renewable portfolio standard targets being met, California is increasingly going to rely on natural gas for generation. The left axis is gigawatt hours. The right axis is percentage of, let's see, how do I put this, it is the percentage of total California demand that is met by gas generation in state.

This is not a contractual arrangement. It's simply the amount of gas generation taking place in California divided by state demand. You can see that the numbers increase from about 32, 33 percent up to 48 percent or so over the next ten years. This poses additional risk to the ratepayers of the state.

In the short run, natural gas price volatility can be mitigated using largely financial instruments and storage. In the longer run rate bearers will be exposed to our natural gas prices for either of two possible reasons. One is cyclical development and exploration for natural gas, which creates a gas price cycle of about two or three years in duration.

We are apparently on the upswing right now, crest and rises as to how much longer that's going to continue. A second source of risk is the notion of dwindling supplies. It is prospected by many that due to increasing extraction costs, limitations on where drilling can take place, depletion of swallowing well drilling in the Gulf of Mexico, that we are doomed to face higher gas prices as we move forward.

These risks can't be mitigated using financial instruments except at very, very high costs. There are some ways one might mitigate these risk. If you can get someone to build an LNG terminal and then sell you gas at ten percent about his cost for the next 20 years, that's one way to do it.

And easier way to do it is simply reduce the demand for electricity, or replace gas generation with generation that uses other fuel sources. Regarding the latter, one of the caveats is you can't then turn around and index the cost of that generation to gas when you've defeated the purpose of turning toward it as a fuel.

So staff ran a scenario in which the

public discharge was increased. This resulted in DSM savings and additional renewables. I'll try to explain what this graph is designed to represent. What staff did was assume that in the event of increased of PGC funding, and a corresponding impact on demand and the development of renewable generation, the market would respond by reducing the amount of gas fired capacity that was built.

For each year here, 2005, 2008 and 2013 you see two columns. The dark blue entry is the amount of gas fired capacity that staff assumed would be added in California during that year. So you can see from the first column staff assumed about 2,700 megawatts being added in 2005.

When it developed the high PGC scenario, it assumed that demand would fall slightly, as indicated by the red entry in the second column, and the market would respond by reducing the amount of gas capacity it had at ever so slightly.

2005, the impact isn't very substantial, but if you look at 2008, in our baseline studies, we assume that a very small amount of gas fire capacity would be added, about 200 megawatts. In the high PGC scenario we assume that no gas prior capacity would be added.

That peak loads would have fallen as a result of demand site management by about 250 megawatts, and that about 80 megawatts of renewable capacity would be added over and above what would be added in the baseline case. The baseline case of course met our PS targets.

This assumed that even more capacity would be added. The figures are about 50 percent higher. So in the baseline case, meeting the RPS requirement assumes the additional of about 3,700 megawatts of renewable generation. In this case, we added 50 percent more, or about 5,500 megawatts.

So and the results are somewhat intriguing. We find that gas fire generation falls by about seven and a half percent. What we end up with the end is that renewables produce about 9,200 gigawatt hours more generation. We assume that the RPS will lead to about 18 or 19,000 gigawatt hours by 2013 of renewable generation, above and beyond what existing renewables will provide.

In this scenario it comes to a total of about 27,000 gigawatt hours of renewables. Energy consumption in the state, as a result of increase DSM savings, fallen by about 10,000 gigawatt hours. The total is 19,000 gigawatt hours. This is almost all gas fired generation no longer being necessary.

This is on a WCC wide basis. About half that generation savings would take place in California. So you look at a 10,000 gigawatt hour reduction in the amount of generation from gas fire capacity in California. It's about seven and a half percent of the total.

And as the least efficient gas is being displaced we see that gas use falls by about nine percent among California generators. This will have an effect on the natural gas price, which back of the envelope said the assumptions means that the natural gas price falls between one and two percent resulting in additional savings of California ratepayers.

So I believe that concludes my presentation. There is nothing beyond this which is reacted. So I will be -- either that or everything is reacted. I'll be happy to take questions. Judy Grau is going to discuss transmission adequacy, transmission issues during the next ten years.

So you can save questions until afterwards, points of clarification.

MR. ALVARADO: Yeah. Judy, why don't you give your presentation and maybe have you both sit up over here and fuel any questions, considering that you've given quite a bit of material to digest there.

MS. GRAU: I don't have any amusing slides to begin my presentation. Mine is more boring. But anyway, can you all hear me? Yes. I have to speak right into it, right?

MR. ALVARADO: Yes.

MS. GRAU: Okay.

PRESIDING MEMBER BOYD: Maybe you learned as David got more comfortable and he begin to turn more towards the audience --

MS. GRAU: All right.

PRESIDING MEMBER BOYD: -- that the mike didn't work as well. So you kind of have to be faced right at it to work all the time.

MS. GRAU: Okay. I'll do my best here. Okay. I want to begin just by mentioning that this presentation was a collaborative effort among several people, include David Vidaver, as well as

Bob Strand, Don Kondoleon, Jim McCluskey, Mark Hesters and myself. Most of them are here today, so if you have any specific clarifying questions that I can't respond to one of them hopefully will jump up and help on that.

Okay. I have four major areas I want to cover this morning. The first is an update on the upgrades we assumed in the simulations. In February we published the infrastructure assumptions report. Some of these projects that we are assuming have had some major rulings or other things happen up to then and since then, so I'll give a real update.

First, a little status of what projects we assumed in February. And then an update on each of them more specifically. And then talk about some of the major obstacles to development of transmission projects, what are some of the things that are going on right now in the state, as well as beyond the state to facilitate the development of appropriate transmission resources.

And then finally, a little overview on some additional on what staff is doing in this IEPR cycle, as well as follow on update process next year to hopefully do our best to bring -- to continue facilitating the development of resources.

Okay. So first of all, if you recall, or if you had our February report, we had seven projects that are large enough to be modeled in the markets and model, which are folks up in the engineering analysis office run. And so first let me briefly go over each of these seven projects, what they are.

And so I'll begin with pat 15. This would add a third 500 killavolt line between Los Banos and GATES. The actual cap is longer than that, but the part that's constrained where there are only two 500 KV lines instead of three is just from Los Banos to GATES.

This is an economic project sponsored by Trans-elect, and independent transmission organization, and Wester Area Power Administration, WAPA, and PG&E. And it's designed to help relieve congestion on that path. And our assumption in the February infrastructure assumptions report was that this upgrade would increase the cell to north rating from 3,900 megawatts to 5,400 megawatts, an increase of 1,5000 megawatts.

And in the north to south direction, increase from 2,130 megawatts to 3,265 megawatts in January of 2005. The path 26 upgrade is from PG&E's midway substation to Southern California Edison's Vincent Substation. And this upgrade that we're referring to here is an operating procedure change that would allow for an additional 400 megawatts increase in transfer capability to help relieve congestion on this path.

And this is being accomplished by it's starting a new remedial action scheme to drop new generation in the midway area in the event of a contingency. So it's not a reconductering. It's not new lines. It's more an operating procedure changes.

And our assumption in the February report was that this upgrade would increase the directional path rating from 3,000 to 3,400 megawatts in October 2003. The path 45 consists of (indiscernible) from Mexico Comision Ferale de Electricidad into San Diego Gas and Electric's territory.

And the physical upgrades needed to increase the south to north rating from 408 megawatts to 800 megawatts were accomplished in November of 2001. But the WECC has not yet improved the increase in the rating for the summer months. And our assumption in the February report was that this approval would occur by January 2003.

The fourth bullet there, the San Diego Gas and Electric Migues to Mission upgrade, would convert an existing 13869 KV line to a 230 KV line. Included in this upgrade is the addition of a second transformer at the San Diego Gas and Electric Imperial Valley Substation.

Our assumption in the February report was this economic upgrade would increase the transfer capability into Downtown San Diego from 1,690 megawatts to 2,250 megawatts as of January 2005. This is a total increase of 560 megawatts.

The staff is assuming that the transmission upgrade of the southern portion of 5.6 will be necessary in the future in order to accommodate possible future geothermal development in the Salton Sea area that may respond to the renewable portfolio standard program.

Our section in the February report was this project would increase the path rating between the Imperial Irrigation District and Southern California Edison by directionally from 600 megawatts to 1,600 megawatts for an increase of 1,000 megawatts as of January 2009.

The sixth project, Jefferson-Martin is one that David Vidaver has mentioned in a couple of different context in the San Francisco area being the liability constraint. This is a new 230 KV line proposed by PG&E, as he mentioned, for reliability purposes, unlike many of the other projects, which are primarily economic projects to relieve congestion.

PG&E filed for a certificate of public convenience and necessity, a CPCN, with the PUC on September 30th, 2002. Our assumption in the February report was that this new line would increase the transfer capability from the north of path 15 area into the City of San Francisco from 700 megawatts to 1,100 megawatts as of January 2006 for an increase of 400 megawatts.

And finally, the Valley Rainbow Project would be a new 500 KV line connecting to Southern California Edison's existing substation with a new San Diego Gas an Electric Rainbow Substation. Our assumption in the February report was that this project would increase the San Diego Gas and Electric to Southern California Edison path rating from 700 to 1,450 megawatts.

And in the other direction from SCE to SDG&E, path rating from 200 megawatts to 2,950 megawatts as of January 2009. Okay. This slide shows the market how the transmission system is modeled. Okay. And I'll attempt to show these with a little pointer here starting at the top.

The Jefferson-Martin line would be modeled as going between north at path 15 and the San Francisco area. The numbers here indicate 700 megawatts. It's the current transfer capability. And then the second number is the increase with the month and year that that would take effect.

So path 15 -- I'm sorry, Jefferson-Martin is between here and here. North of path 15 to zonal path 26 would be the path 15 upgrade, as we discussed between zonal path 26 and Southern California Edison is path 26, which is the midway to Vincent. From Southern California Edison to San Diego Gas and Electric would be the Valley Rainbow new connection.

From Southern California Edison to IID is the 1,000 megawatts we are assuming needed to bring new generation that may respond to the RPS program, the new thermal in the Salton Sea to connect that. And then from Southern -- I'm sorry, San Diego Gas and Electric down to Miguel would the Mission Miguel Project.

And then finally path 45 is the two lines connecting the major areas in Mexico up to across the border, San Diego. And we split the 800 megawatts, 400 here and 400 here just for simplicity. Okay.

So now that we're familiar with the seven major projects, I want to give an update on what has happened since our infrastructure substance report in February. Beginning with path 15, the first bullet is just repeating what I already said. So I won't mention that.

The current status though is on May 22nd, of this year the PUC voted to allow PG&E to withdraw its CPCN application, and that also approved the final supplemental environmental impact report as the environmental impact report for the project. And so between these two actions it allows PG&E to proceed with the project under federal authority with its partners, Trans Elect and the Western Area of Power Administration, WAPA.

And Morteza Sabet Sava of WAPA is here today, and he can give you more details on the status of the project if you would like after the formal presentation. Just in brief, they've now chosen a contractor and the project is moving forward. Morteza can tell you more about that.

Okay. On path 26, as I mentioned, this is a remedial scheme upgrade primarily, and the timing of it had not been affected by the March 21st, Vincent Substation fire. Some of you may know there was an explosion and fire at Southern California Edison's Vincent Substation, transformer bank number two.

They had three transformers there. Number two was irreplaceably damaged. So as a result, the current transfer capability for the two working transformers is currently limited to 2,500 megawatts. But a fourth transformer had already been planned for the Vincent Substation.

So now its installation is being expedited. And that will allow a return to the 3,000 megawatt rating in July. And then the remedial action scheme upgrade would then bring the rating up to 3,400 megawatts.

The predicted on line date for that now is November 2003. So in terms of that, there's no modeling impact because their simulation doesn't become -- doesn't begin until January 2004. So we're still on schedule from that respect. Okay. On path 45, we had said back in February that the CC approval would already have occurred, or been imminent.

It's now expected to occur in mid July of this year. And, again, the modeling impact is none because we don't begin our simulations until January 2004. On a related note though, there was a May 3rd, ruling by Judge Gonzalez who wrote that the DOE and Bureau of Land Management violated the National Environmental Policy Act by failing to fully recognize the potential error of water quality impacts when it approved the permits for the construction and operation of transmission lines linking two new power plans in Mexicalli, Mexico.

One is Sempra 600 megawatts, Electra de Mexicalli Plant. And the other is Intergen 560 megawatt La Rosita Plant. And these connect directly to the grid in Imperial County, although the power plants are located in Mexico.

And the court has scheduled a June 16th, hearing for the remedy portion of this case, which will determine what the DOE needs to do to comply with NEPA and the court ruling. And on June 4th, the group of cross border residence and health organizations and environmental groups asked the judge to halt imports to California from these plants.

I'm not sure if La Rosita is up and running, but I know that Termo Electrica de Mexicali Plant, the Sempra Plant, has been up and running and had been providing power. And so Judge Gonzales is supposed to rule any day now on the temporary restraining order.

Okay. On the Miguel Mission, the day after we gave our presentation back in February, the PUC approved the Miguel Mission upgrade and the Imperial Valley Substation modifications, and found that both projects are economic and in the public interest.

A CPCN is not required for the Imperial Valley modifications, but is needed for the Miguel Mission upgrade. Although the PUC said they would expedite that process. And that decision also set a cost cap of 55.4 million dollars for both the

Imperial Valley upgrades and the Mission Miguel upgrades.

Path 46, this is our generic assumption to bring increased renewables from the Salton Sea area out in the Imperial Irrigation District area. We're not changing that assumption. So that's still valid. And on Jefferson-Martin, on March 19th, the administrative law judge at least a scoping memo of ruling, and it basically sets the scope for the project.

It includes PG&E's preferred route, alternative routes, the no project alternative, and non wires alternatives. And it also set a schedule for release of a draft environmental impact report in July 2003. And evidentiary hearings in December of 2003, and a decision in May 2003.

So our modeling impact, we have the project coming on line January 2006. And we believe that's still feasible based on that schedule, assuming a positive finding. Valley Rainbow just, what, five days ago, at the PUC's business meeting, they voted against on split decision San Diego's Gas and Electric's petition for modification.

So what that means is that San Diego Gas and Electric cannot reopen the case unless they start over with a new application. At this point, San Diego Gas and Electric has not publicly announced its plans, and I'm not sure if there's anyone here who would like to speak further on the issue.

But we just want to note that the project is included in San Diego Gas and Electric's 20-year electric resource plan that was filed with the PUC on April 15th. And they call that project the near term interconnection project. And it's part of a larger plan to improve the backbone of the 500 KV system in the area.

And as they note in the 20-year plan, the soonest that short -- the near term interconnection project, which is essentially Valley Rainbow, the soonest that project could be built is 2008. And our assumption has been, and is, January 2009.

Okay. I want to switch now from modeling impacts to some of the obstacles, to the development of transmission projects. We've kind of grouped in three major areas, planning, permitting and financial. And beginning with planning, we believe that the state's perspective is often not adequately incorporated into transmission planning activities.

And so the broad principles and interest of the state are not always considered, such as efficient use of the existing system and rights of way. And these are what we call the Garamendi principles that we've been advocating for many years.

Also, long-term strategic expansion of the system may not be adequately considered, planning for future right of way needs and balancing the environmental goals with system reliability and economic needs of the state. With respect to the permitting process, their permitting processes for various types of transmission projects are often fragmented and overlapping.

An environmental analysis are sometimes inconsistent and, as we mentioned, state wide benefits may not be adequately considered. The PUC's CPCN process, certificate of public consumes and necessity, looks at the economic need for the project within the context of ratepayer benefits.

And thus, the strategic benefits of a project may not be adequately addressed. Such strategic benefits maybe regional or statewide in nature. Whereas, we also recognize the physical impacts of this project are local. So as a result there's often strong local opposition to transmission projects because of concerns about visual, environmental or property value impacts.

For the financial side, private investment and transmission has been slowed by the financial distress of some developers, as well as regulatory and economic uncertainty. The next two slides talk a little bit about some of the actions being taken by the state and others to facilitate the development of transmission resources.

Beginning of course with our SB1389 mandate, which provides a mechanism for the Energy Commission to corroborate with appropriate state and federal agencies, and encourage cooperation among state agencies that have energy responsibilities.

And this mandate states that the results of the Energy Commission analysis shall be made available to such agencies in order to provide a common basis for decisions. This state energy action plan has recently been adopted by the three collaborating entities, the Energy Commission, the Public Utilities Commission, and the California Power Authority.

And it contains the goal. It explicitly states the state will reinvigorate its planning, permitting and funding process to assure that necessary improvements and expansions to the bolt electricity grid on made on a timely basis.

So, again, the planning, permitting and funding processes, those are the major obstacles I just had in my last slide. So it's kind of a validation of those three major areas. And one of the action items for achieving this goal is to explicitly require the agencies to participate in the Energy Commission's Integrated Planning process to determine the statewide need for a particular bolt transmission projects.

The IEPR update process, the third bullet, I'll be talking more about that on the last two slides. But right now I just want to say that SB 1389, if you look at section 25302D, provides for an off year update due November 1st, 2004, a year from now.

That provides for policy review, as well as an opportunity for raising new issues that have emerged since the release of our plant, November 2003 report. Okay. The next group of items, beginning common analytical tools, those of you who are the PUC's investigation 00-11-001, it's a multi-phase transmission constraint related proceeding.

And phase V of that proceeding is looking at the development of a generic methodology for evaluating the economic need for transmission upgrades. The California ISO, who I believe is here today, Robert Sparks, yeah, maybe can talk more about that.

But they've been working with London Economics International on a generic methodology. They issues a draft report in the end of February. However, since that time it's become apparent that the ISO needs more time to more fully develop and apply the methodology. And it may take up to a year for the ISO to validate the methodology.

And on April 10th, of this year the ALJ Gottstein ruled that this phase of the proceeding would be deferred until the ISO has validated the network. And until the ISO and/or other respondents have completed a study, using the proposed methodology on a specific high priority transmission project.

With the respect to strategic long-term planning, the Energy Commission and the ISO have initiated an effort to ensure that long-term planning and strategic project benefits are included in the state's IEPR process, and in the ISO's transmission planning process.

With respect to vocational marginal pricing, in late May the ISO made public its revised draft proposal for market redesign, and it includes provisions for creating a day ahead, an hour ahead, markets that operate on location marginal pricing.

And this would create I believe it's like 3,000 notes in California, as opposed to the current system, the Zonal approach, which relies on just three zones in California. So this would provide by having more notes, more transparent knowledge of where the constraints are, and give the signals to developers, generation or transmission, of where they could they could most benefit the system.

And finally, FERC incentives, the

Federal Energy Regulatory Commission is encouraging public utilities to join regional transmission organizations, or form independent transmission companies, and is providing a return on equity incentive for those who do so.

The last thing I want to talk about is staff's transmission study plan and white paper. What we're trying to do is conduct a preliminary analysis, a representative transmission projects to determine if there are statewide benefits.

And we believe this analysis response to our mandate to assess the availability, reliability and efficiency of the Western Regional and California Transmission system. And also the response to the recently adopted state energy action plan, which asks the agency, including the ISO, to work together to ensure that state objective are evaluated and balanced, and determined in transmission investment that best meet the needs of Californians.

We are going to publish a white paper July 25th, which is concurrent with our electricity and natural gas report. And we also have plans for future work, as I mentioned, in the update cycle, which is the off year report due

November 2004.

And so in case none of you were able to figure it out because we didn't mention the names in the infrastructure assessment report, we just called them a major interstate economic project, that would be the second Palo Verdes DEVERS line.

The major interest rate intra-utility project is the Valley Rainbow Project. The intra-utility reliability project is PG&E Jefferson-Martin Project. And the intra-utility RPS project is Tehachapi.

And so for each of these projects we will be performing a recognizance level economic and/or qualitative assessment of the benefits using our in-house technical expertise. So the results of these analysis will be contained in our white paper. We've preliminary entitled it California's Electric's Transmission System Issues and Solutions, or something like that.

As I mentioned it, we're going to release it concurrent with the electricity and natural gas report on July 25th. And in the white paper we're also going to identify the potential critical issues associated with each of these projects. And provide direction on what staff would like to accomplish in the next 12 months or so in the IPER update process.

And we'll also update the reader of the status of the most noteworthy actions being taken to facilitate the development of transmission resources, the seven bullets where we just talked about the actions being taken by the state and others.

So that concludes my presentation. I will turn it back over to Al for the moment. He'll tell us what we're going to do next.

MR. ALVARADO: Well, Commissioners, I was going to suggest taking a ten minute break before we open up to any questions or comments that we may have from the public. So I suggest, let's say, we reconvene at ten after 11:00.

PRESIDING MEMBER BOYD: Five after.

MR. ALVARADO: Let's make it five after 11:00.

(Off the record.)

MR. SABET: Good morning. I'm Morteza Sabet of Western Area Power. Basically, we are on our way. And based on what I got yesterday, we have about two-thirds of a right away acquired, and about three-fourths of an access road for construction maintenance, also done.

And hoping to start the construction this summer and be done by fall of 2004. Hopefully before the original date that we forecasted, December of 2004. And I trust PG&E's portion, I was told that is going to be done at the same time.

So the project will energized late 2004. So anything else?

PRESIDING MEMBER BOYD: No. Well, this is a question for our staff, and maybe for you, I'm not sure. It's almost not relevant, but I don't a form like this on transmission very often. I believe you recall that in the summer of 2001 there was an effort to fix path 15.

It was aborted by, what I thought at the time, unilateral action of the PUC to order PG&E to fix path 15. I'm just wondering, I've never had a good explanation, and I don't know if I want one in public today, but I'm still going to be seeking an explanation from our staff of, you know, why that crashed and burned, and is the current solution a better solution than the solution that was being pursued in 2001?

Because, frankly, the deadline then was

to have this thing up and running in 2000, or at the beginning of 2004, end of 2003. And to me, we've lost a lot of time.

MR. SABET: I was a witness in that area, but I take the fifth on that one.

PRESIDING MEMBER BOYD: Yeah. Okay. I think a lot of people have for a long time. So I'll just put our staff on notice that one of these days in the privacy of my office I'd like to have a little chit chat.

MR. SABET: Thank you.

CHAIRMAN KEESE: I'd like to ask with regard to the transmission, we had -- you had listed seven projects. Is it staff's position that all seven of those projects are needed?

MS. GRAU: Well, okay, in terms of need, we're not going to comment I think on the ones that are going through the CPCN process. But there's reliability need and there's economic need. And in terms of the reliability need, I think -- again, I don't want to put words in other staff's mouth but, you know, we have staff who look at the -- specialize in the San Francisco area.

And from a reliability standpoint, and I think Dave mentioned also, Jefferson-Martin, if it's not built, there will be a problem beginning in is it 2004 or 2005?

CHAIRMAN KEESE: That's my next question then, because I heard Jefferson-Martin in 2006.

MS. GRAU: That's our staff assumption was that it would be built and on line by then. But I think the schedule for the CPCN -- I forgot what I said in my slides, but they're not even going to make a decision until -- I'm sorry, I lost my train of thought.

CHAIRMAN KEESE: So I accept to the 2006 as --

MS. GRAU: May of 2004. So the soonest we can come out to be built after that process. So we assume January 2006.

CHAIRMAN KEESE: And is that enough to meet the reliability needs in San Francisco? It seems to me that the reliability needs in San Francisco are current.

MS. GRAU: Yes. When did you believe that -- you said (indiscernible) and what not would occur.

MR. VIDAVER: I may have illusion to the possibility that there would be curtailments in

San Francisco. San Francisco is just a series of very, very old plants with very, very high outage rates. So when you simulate what happens there occasionally you get two or three of those plants going down and you can't keep the lights on.

CHAIRMAN KEESE: So it could happen anytime now, and the earliest that Jefferson-Martin can come on is 2006?

MR.VIDAVER: We would generally agree that there maybe -- it's not an unreasonable possibility that you'd have to turn the lights out in San Francisco. We came very close I believe it was in December of 2001 to that happening. I remember all of us sort of watching what was going on.

And had one even small GT tripped in San Francisco, the lights were going out.

CHAIRMAN KEESE: With respect to Valley Rainbow, and I'm trying to avoid appropriateness, you know, whether that line as proportionate built, that it seems to me that is the other one you put in the reliability category.

MS. GRAU: I believe when it was filed with the PUC it was couched as a reliability project. But like a lot of projects, they're both reliability and economic sides to most projects. And I believe now they classify it as an economic project.

CHAIRMAN KEESE: And so we didn't make a judgement that something like that is needed for reliability, independent probably of that process?

MS. GRAU: No, not for reliability purposes. What it is is it has the opportunity to reduce R&R contracts in the area. And, you know, I'm going to let Mark Hesters bail me out on this one.

MR. HESTERS: When we were making these assumptions about transmission lines for this model, they're not -- I just wanted to be clear, they're not an endorsement of the project. They're more of a -- you have to make a planning assumption that something is going to happen.

You can assume nothing happens, and that could be right, but it's probably going to be wrong. And we just decided that we thought something was needed in San Diego, and that Rainbow Valley was a pretty reasonable assumption for something that was going to happen.

Whether it's exactly Rainbow Valley or it's something completely different, Rainbow

Valley is the best sort of picture that we have so far. And that's where that comes from.

CHAIRMAN KEESE: So to characterize the seven that were on your list, starting with path 15, those are the ones that are in the ISO planning perspective, the planning perspective, the Energy Commission planning perspective. Those are the seven chief projects that are being discussed, is that --

MS. GRAU: Yes, but within the context of how they are modeled in Henwood. For example, Tehachapi you notice we didn't talk about that in there because that, within the notes, that diagram, that very complicated diagram, I showed some projects are within a note, and so they do not show up.

So these are major intra-noble from the standpoint of the Henwood Markinson model. These are the major ones that we believe will --

CHAIRMAN KEESE: That we discussed.

MS. GRAU: That we are assuming will be built, yes. Yes.

CHAIRMAN KEESE: We're not making a determination. We're saying these are on the horizon.

MS. GRAU: No, these are just for planning assumptions. These are the ones we are assuming in those time frames.

PRESIDING MEMBER BOYD: Because Valley Rainbow was just referenced in that it's off the table now as of June 5th, do you have a hole in your analysis? I mean you assume something. We're not endorsing specific projects. You assume something in San Diego. This was the Bible candidate. Now, there's a black hole there in my mind. What does that do to your assumption?

MS. GRAU: Well, I think just carrying on with what Mark Hesters said, for planning assumptions, we need to assume something. And as I also mentioned, in San Diego's 20-year plan, they now show that Valley Rainbow Project is part of a larger backbone improvement project that would actually connect from the existing Southern California Edison Valley Substation down to a new Rainbow Substation in San Diego's territory, and then further connecting that new Rainbow Substation over to Imperial Irrigation, Imperial Valley Substation.

So it would make a ring around that completes the loop. And so in the 20-year plan that's a vital part of their plan.

PRESIDING MEMBER BOYD: Don, why don't you step up. Okay.

MR. KONDOLEON: Yeah. Commissioner, Boyd, this is Don Kondoleon again with the Energy Commission staff. A number, of course, as Judy alluded to at the presentation, we're going to be doing an evaluation of four projects, one of those was included in the Valley Rainbow Project.

So we will be doing an examination of the benefits of that project, irrespective of the decisions that were made over in San Francisco. I think we still believe that that project has portrayed in the 20-year plan for San Diego, makes some sense, especially one done in conjunction with other projects.

And I think that's how the projects are portrayed now by San Diego Gas and Electric. I think one of the issues with regard to the Valley Rainbow Project in the information that was presented in the CPCN is that a project was presented in isolated. When in isolation it's difficult to necessarily measure the benefits from that project.

I think when you're looking at a

conjunction to other additions to the system, you can start to see the value of increasing transport capability, both into San Diego, and also the ability to transport power from San Diego to the north once you've got that highway down to Mexico and are able to access that strand of generation that now exists south of the border.

So those are the sorts of things we want to try to do in the IEPR process and the update process here at the Commission, using our own tools and working closely with ISO staff and the utilities.

MS. GRAU: May I just add one more point, in the Valley Rainbow decision to deny it, they were only looking at a five-year time horizon. And they said the project was not needed until at least 2008. And so by denying it, they're not denying it categorically forever.

It's just within the time frame. And so we did not assume it would be on line until January 2009. There is still a possibility that San Diego could refile such a project. And it could be found needed, you know, in a later time horizon.

CHAIRMAN KEESE: I was going to follow

up on your suggestion and ask if there does happen to be anybody from San Diego here who would feel that they could comment on this and tell us if there is a plan by San Diego at this time?

MR. BING: I'm Chris Bing, regulatory affairs, of course, San Diego Gas and Electric. You know, this isn't a project that I'm assigned to at Valley Rainbow, but I do know that at this point there has not been a decision made as to whether SDG will refile.

And as far as when that decision is going to come, I really don't know, but we can keep in contact with Commission staff and advise you as soon as it happens.

CHAIRMAN KEESE: Thank you.

MR. ALVARADO: If you have a business card to provide, our court reporter, he would appreciate that. Thanks.

CHAIRMAN KEESE: That's the end of my questions.

PRESIDING MEMBER BOYD: I have no more.

MR. ALVARADO: I was wondering, while we're on the topic of transmission, I know that the California ISO is here, and I believe, Mr. Sparks, did you have some comments while we're on the topic of some transmission issues?

MR. SPARKS: Sure, should I --

MR. ALVARADO: Yes, please come up.

MR. SPARKS: (Inaudible) that Don asked me to prepare or think about. Did you want me to try and address the questions that you were asking? I have sort of have a little canned comments here. I'll just go through them. Maybe I can touch on them, potential Valley Rainbow impacts.

I'm Robert Sparks from the California ISO. I just wanted to point out that the California ISO is participating in the SSG-WI process, the RTO scene steering group, Western Interconnect process. SSG-WI will be performing at WECC wide long-term transmission study.

And the ISO will be submitting projects to the SSG-WI process for them to evaluate in their study. These ISO projects, or the ISO will develop these projects with groups of stake holders through the STEP study process, which is the southwest transmission expansion planning, or plan process, which is a rigorous study that's currently ongoing to analyze transmission projects between the southwest and Southern California, or

Arizona, Southern Nevada, New Mexico, and Southern California.

The ISO is also working on an abbreviated assessment of the transmission system between the northwest and California, and within California to possibly identify additional projects to submit to the SSG-WI project for their analysis.

And we are working with, and following along, in the IEPR process, and trying to integrate with all the various processes. A couple questions came up, one was on the London economics methodology. The ISO is working with a vendor on developing a detailed network model that would be compatible with that vendor's market simulation package.

And that is currently the delay. I think it was referred to earlier in discussing I think it's even called the phase V CPUC AB970 process. But in the interim we are using the ABB's market simulation, or market simulator package, for both the SSG-WI and the STEP analysis.

And as far as Valley Rainbow goes, I think it's anticipated that the STEP may provide a long-term plan, which could show the benefits of the ring that Judy talked about, connecting Imperial Valley to Rainbow and eventually Imperial Valley Substation. That is in Imperial County.

To Rainbow and then to Valley. And that may -- I mean there's Victor looking at about 16 different alternatives. It's quite a number, but hopefully they'll come up with a short list. But those projects are certainly part of the various alternatives that they're going through quickly.

In September they hope to have a short list to present to SSG-WI for the analysis. So that's all I had. I did have one question since I'm here. The four projects that will be analyzed, one of them was Tehachapi. And I think earlier it was said that an analysis of the benefits of these projects will be performed.

And my question is, is there -- what exactly which Tehachapi -- what does the scope of the Tehachapi project that would be analyzed?

MR. HESTERS: The Tehachapi project that we're analyzing is less of a transmission analysis, and more of a value of wind analysis. It sort of starts with the assumption that enough transmission is going to be built to get sort of the maximum amount of wind out of Tehachapi, and goes from there.

And so essentially we simplified it to a single 230 KV substation with a lot of wind, and then lines feeding that, feeding (indiscernible). Does that answer your question?

MR. SPARKS: Yeah, yeah.

MR. HESTERS: Okay.

MR. SPARKS: It's essentially assuming a simplified type project, but not a detailed analysis of I guess the impacts of that project on the rest of the grid or -- the reason I ask is the ISO has presented some testimony in phase VI of the CPUC AB970 process recommending that other alternatives will at least be analyzed, that could be electrically substantially different than just a radio line.

But anyway, it's just a question. We can talk about --

MR. HESTERS: We knew about those alternatives, but we didn't have enough information to model them very well. And decided that rather than try and make a wild guess we would just start with the assumption that anything that is built is going to be big enough to get the wind out and go from there.

MR. SPARKS: Yeah. I think it's the one concern maybe, and I maybe speaking only for myself, would be that a conclusion has come up that it's not economic to build the transmission when not all of the alternatives have been looked at yet.

CHAIRMAN KEESE: Since I have both you and staff here, what is the assumption with regard to Mexican generation? Are you assuming that the current plants that are either on line or on line next week is what's feeding in? Or are you making any assumptions with regard to additional generation forces in Mexico that would impact the transmission plant here?

UNIDENTIFIED MALE: I am not participating directly in the STEP process. I'm more the northern guy at the ISO. I defer that question back to the panel.

MR. HESTERS: We're using two different modeling systems, and keeping the assumptions consistent. I don't have it sitting right in front of me, which plants we've assumed on line. We've assumed the ones that are built are going to be operating.

CHAIRMAN KEESE: But, you know, you're now making an assumption about major expansion of Mexican generation on how it could be accommodated.

MR. VIDAVER: No, I don't know the number off the top of my head, but I don't believe that it's substantial, that we add something on the order of maybe 600 megawatts. And to be honest, I don't remember whether we had it at La Rosita or in Tijuana.

CHAIRMAN KEESE: I was just thinking of some of the proposals. Some of the L&G proposals suggest major transmission going across I believe to Aron Bery. Not coming to San Diego, but heading over to the Arizona, California border. That's not in the plans?

MR. VIDAVER: No, we haven't modeled the scenario like that, no.

PRESIDING MEMBER BOYD: I want to go back to Tehachapi for just a moment. I don't want to put anybody on the spot, but it's not too often we get an opportunity to discuss these things. And I understood the discussion.

But when it comes down to, you know, policy issues, which is what part of the November report is all about, you know, Commissioners sit around in hearings on occasion and told repeatedly that the Tehachapi link is a very weak link, and it's prohibiting desirable development of wind in the area.

And then I hear this discussion about assumptions made and not made, and alternatives need to be looked at. It doesn't make me feel real warm and fuzzy about there's a solution to the alleged problem in the Tehachapi area forthcoming in the immediate future.

And Tehachapi has been talked about as a problem to me long before I even came to work here at the Commission. So, again, it seems to be another one of those that just goes on, and on and on. And maybe I'm wrong, but somewhere in this process I would like to get a handle on is there a policy issue here or isn't there?

Are things being handled expeditiously in that area? And now I hear a new discussion of a need to look at alternatives, which is fine. But where's the bottom line, you know? When do we finally get to some decision that either, you know, we're not going to develop anymore wind in the area because it's not the right thing to do.

Or we are and we need transmission, or we need something, you know.

And it's going to get in the cue and get done. I mean life does not slow down. It's the ever accelerating pace of everything, which goes back to my mild impatience with path 15 taking longer than what I was told it would take, etcetera, etcetera.

So Tehachapi is another one just seems to sit there forever and ever. I don't know if you have any additional responses today, but it is to me, quote, a policy issue that doesn't seem to get resolved at the --

MS. GRAU: Okay. Go ahead.

MR. KONDOLEON: Well, you know, I've been involved in this too, as you know, Commissioner Boyd, since way back when with the green team that we looked at the --

PRESIDING MEMBER BOYD: You should have more white hair than I.

MR. KONDOLEON: I'm working on it. But as you well know, there's been an issue for a number of years between the developers and the incumbent utility. Edison and developers had problems for many years. And one of the things I think we were able to accomplish through the green team was finally to get parties to work together and look at, and it led to development of these conceptual studies, as referred to by Mr. Sparks.

Basically what's happened has been a look at what possibly would be needed to support maximum amount of wind development in the Tehachapi region. And I think we're talking on the order of two to 3,000 megawatts. And what was developed in the second conceptual study was, you know, sort of a preliminary examination of options with regard to construction of I think up to four 230 KV substations, a number of feeder lines, and one new 230 line.

And that was proposed by Edison and the developers. The ISO then sort of took a look at it and made some suggestions I believe, including maybe potentially interconnecting to PG&E's system as opposed to just running it through Edison's system.

The bottom line is, again, it's sort of two issues, one is the existing problem, which is the inability of the existing system really to support more than about 325 megawatts I believe is the number of generation because of the 6669 KV system that it currently transports, most of that power into the Edison network.

And then the second thing is looking at, again, at this potential for RPS development up to 2,000 to 3,000 megawatts and the need for expansion of facilities. And what we've tried to do here at staff level, as Mark talked about earlier, was, you know, looking at the time frame we had for analysis.

What could we do using our tools in a short time frame to try to provide some input into the potential value. And what we did is, again, kind of do a simplified network of fix, which was sort of look at what was proposed by the team, which included Edison and developers, look at the (indiscernible) that the ISO provided.

And then looking, again, on our own constraints using our own tools, and manpower and stuff, and came up with the idea that, well, we'll just kind of do this as simplicity fix, at least for the short-term. And really, as I say, as Mark alluded to, it really comes to an examination of really what the potential benefits would be of the wind generation at this point, absent having any capability to do the detailed studies.

What we've talked about potentially doing in the IEPR updates cycle, you know, starting next year, if in fact the Commission feels strongly about us proceeding, I think then we'd get into the more detailed assessments that are necessary to really assess the value of that sort of interconnection.

And I'm talking about the number of projects and substations that are involved. But, again, I think more than likely we're probably a ways away from doing that, given the that fact, as we said, that the ISO is sort of looking at things a little bit differently than what the team had up to this point.

And I don't think we're at the position right now to say one is better than the other. As I said, what we tried to do in our process here now is to work cooperatively with ISO and the utilities to try to reach, you know, solutions that we think are in the best interest of the state.

PRESIDING MEMBER BOYD: Thank you.

MR. ALVARADO: Thank you, Don. We've definitely covered a whole spectrum of different issues today. We've talked about short-term outlook for our supply adequacy. David has also talked about the long-term evaluation or different scenario studies. What we're seeking here, if you have any clarifying questions or comments, not just what was discussed today, but the content of the report itself.

CHAIRMAN KEESE: We have an impressive audience.

PRESIDING MEMBER BOYD: It's time we start hearing from the public.

MR. KELLY: Good morning, Commissioners, staff. Steven Kelly with the Independent Energy Producers Association. And since there doesn't seem to be a rush of a billion people to come up here, maybe I'll take the liberty of taking some time. What I'd like to do if I could is I'm going to step back to the 40,000 foot level and just address, you know, my initial kind of personal impressions about where we are in the planning process an so forth.

And then maybe move to get into some specifics about the report itself, provide perhaps some recommendations on how they might be improved for stake holders such as myself, or outside the Commission. Looking at these reports on a daily basis, trying to ascertain what they mean and so forth.

I guess I'd start with back in March or February when he had the initial workshop on the assumption reports. I made the comment, I think, it was difficult for stake holders to take these reports and understand what you wanted from us.

And more importantly, I think I said I find it hard to understand how policy makers can utilize these reports to anticipate, and be informed about, the decisions that you're going to have to make in the next six months, 18 months, 24 months or whatever because of the way that, you know, you need to, as policy makers, need to anticipate things before they occur.

You need to know what the status quo is today. You need to know, I think, what is going to happen if nothing happens. And this report imbeds in it a lot of assumptions throughout the document. It was very difficult for stake holders such as myself to decipher what it's meaning, or what it pretends to mean.

Because it's kind of integrated kind of the picture of where we are, a lot of assumptions. And sometimes those assumptions aren't clearly stated. And secondly, the piece that I think may be missing in this is telling the market place, policy makers, not only what the assumptions are, but when on a timeline is a decision going to have to be made to act in one or the other to solve a potential problem that you see coming up.

So I'll get into some specifics a little later. But my impression is that right now this report, particularly if it's going to go to the legislature, needs to be tailored in a way that it's going to provide policy makers, particularly with the Commissioners, with information from which they can make informed decisions and predict how to build, make decisions now that are going to have an impact in three or four years.

Regarding the report itself, I'm pleased to see that there is an emphasis, at least in my reading about the importance of regulatory certainty, and long-term contracts to stabilize the electricity market, sending proper signals to generation community, transmission community or whatever about what needs to be built.

The language in this document speaks to that, and I think it's very good that it takes a strong position on that. One of the things that's missing in this, and I'll speak a little later, the timing of the assumptions that are imbedded in this report.

It's not clear to me when I read it the importance of your view of how the energy market, and infrastructure, is going to develop, and the connectedness with ISO having to do a market redesign, or the ISO doing a transmission planning study.

All of which are fairly speculative, and pushed off time and time again. Meanwhile, you're working with a real time dynamics pressured by the Commissioners saying where are we today and what are we supposed to do in the next six months or next year.

But we've got these processes that have fundamental implications for market design. And they continually get pushed off. And it's not clear to me how important that is to what you're all doing in trying to put the information in the picture to the Commissioners together.

And I think that is important for you to manage through in this report, is the interconnectedness between the factual situation that you're trying to describe, the assumptions that you're trying to describe, and the timing that is out of your control.

Because that will help tell the Commissioner, gee, we need to make a decision by now. As an agency, take a position on this matter in order to help these other agencies maybe move forward. The other aspect of the report that I noted is your emphasis on the importance of competitive markets, which I think is good.

There was a reference to the importance of the Spark Spread to new generation. And there's language that speaks to the fact that I think in the near term you think that Spark Spread may be insufficient to send proper signals to generation.

But then on the other hand, you note, I think particularly in the context of the muni's of the LSE's I think you described them as they will move forward and build generation. And I'm puzzled why they will move forward with generation when Spark Spreads are narrow.

Why wouldn't they buy from the market places as much as the IOU's. I think it's probably because they are, from a planning perspective, moving forward and entering into long-term contracts in anticipation of building huge planning reserve.

But that's not clearly said here. And I think you could tease that out a little because you're right on, but you've got two actors making behavior decisions in the environment that are different, seeing the same evidence.

And what is it that's going to fix that? Which way do we want to go and how do we want to send the IOU's in particular, if the muni's are doing it properly, to get into the boat to be doing the same kind of thing.

Another issue that I've noticed in my review of this is, and it's more of a question, it was not clear to me the firmness of the resources that you have imbedded in your plan. And what I'm talking about here are imports, in state generation, DSM, and even the renewable piece.

How firm are your projections, for example on imports? I think you've got a number of about 8,000 imports, megawatts of imports in there. How firm is that? Is that under contract to anybody? And I don't know, I've heard comments that you can't get to that information, but what happens if the Pacific Northwest economic boom reoccurs?

What's the risk or the probability that those resources stay up in the northwest? What's the risk that Denver's booms, Colorado Rocky Mountain Region, and those imports go to the Rocky Mountain Region rather than coming down here? What's the likelihood of that?

I think some of those kinds of issues are important for us as market participants to evaluate the robustness of your assumptions in your whole planning report. And the other similar example is in state generation. There is a significant amount of in state generation that does not have a contract to an in state load-serving entity right now.

A lot of that is being, from my understanding, is being operated pretty much within the ISO market structure, which has some RMR requirements, but also has some other structures on what those generators can do.

What's the likelihood that that generation will escape from that either by not finding it economically feasible to run and shutting down, or selling their generation to an out of state entity?

Similar with DSM, I remember years ago back in the planning days when we had the concept of uncommitted DSM, and committed DSM. You kind of remember that that kind of drove some of the planning assumptions. How firm are we on the assumption of DSM and its robustness continuing over time?

How firm are we on the renewable thing? I'm going to speak in a little greater detail on the renewable issue because you've got some assumptions in there that I think the discussion just touched on about transmission, maybe way off base.

Because you've got an assumption of 1,000 megawatts of wind, where's it going to come from if the transmission in Tehachapi isn't built? And as we've heard, there may be a huge delay in that, if not nothing built because it's not, quote, economic from the ISO's perspective or someplace else.

Where are the 1,000 megawatts going to come from? The other issue that I had, and then on the table you spoke for your one and two, and one in ten projections on operating reserves. And it wasn't clear to me whether that's a WECC operating standard, operating reserve standard, the seven percent number, the definition of operating reserves.

Or was that encapsulating planning reserves as well? It looked to me to be an operating plus planning reserve issue. The WECC's have some certain standards on operating reserves. You've got to maintain seven percent, and they've got have these certain kind of characteristics and readiness and so forth.

The planning reserve is a little different. And that usually gets to the issue of resource adequacy in that planning structure. They're separate in some respects. And I think you need to tease out whether you've got them characterized properly or not.

If they're operating reserves, that's fine. You can probably make a footnote that that's what that is, and it's consistent with the WECC standard. If there's planning reserves in there and they're being driven by assumptions on resource adequacy, we probably need to know that.

And then finally in the report itself, I know the report speaks to the fact that things look fairly good between now and I think 2006, 2007, which is good. That's good news for California. I am concerned though that we're within about ten days of the ISO having issued a stage I alert in the month of May about the status of the California energy structure.

So in my mind, it's how close are we to a very fragile situation if temperatures drive up, you know. This year we're a very robust hydro, but what about next year? I mean I was probably amazed as a number of other market participants because right after you had released your report basically saying things look pretty good as a staff draft, you know, the ISO comes out with, boy, we've got problems here. We're in a stage I.

And I thought we were more robust than that. So I think that is something that we could probably focus on. On transmission related issues, I've just got a general comment, and I've alluded to one, is basically what is the impact of the transmission assumptions on the electricity report?

And, you know, again, going back to the assumption that there's going to be a 1,000 megawatts of wind in California serving the RPS, where's that coming from? And how is important is the transmission assumption on Tehachapi and other places to feed them?

There is an interconnectedness between the transmission and generation. We all recognize that. But it's not clear to me what the interconnectedness is in your modeling. And that happens throughout the document. I mean all the things you're doing is so complex.

And you've got imbedded a series of assumptions, but if one assumption does not come true, is there an expediential effect on another assumption that we're not modeling or thinking of right now? They all seem rather discreet to me at this point.

And I think they are very, very much connected.

MR. ALVARADO: Steve, how about maybe if I could sort of just assert myself here to add a little perspective. As we indicated earlier today, we are holding a whole series of different workshops. There are other subject others, staff reports. We are trying to examine a lot of these different areas, you know.

You're taking a pretty broad brush approach and question to our process. The other day we had a workshop on efficiency issues. We will be having another workshop that's going to cover renewable technologies.

For perspective, what we're doing here, at least on this report, was not coming up with a preferred identified resource, long-term resource plan, as we've done a number of years ago, which involves really getting out a lot of the assumptions we would want to include, engage in a screening analysis to evaluate the benefits of each of the resources.

The study that we're talking about today is really just trying to first identify what kind of uncertainties we could probably confront in the future. Some of these assumptions we've taken regarding renewables in DSM is sort of a figure magnitude to see if so much DSM and renewables were brought into the California system, how that might really effect the need for other new generation.

And further down the line we'd like to examine what would be the implications to the gas system.

MR. KELLY: I understand how complex this is. So don't get me wrong, I mean this a very difficult thing. And there are statewide implications and regional implications. And there's no better agency to deal with even the regional implications of this than this Commission.

You have the expertise, and the people, and the will, and the understanding of how to do this. It's very complicated. But from, you know, a stake holder's perspective, trying to help you in these workshops, grapple with this -- I mean when I first got the report I went through it fairly quickly and then shuffled it off to some people that I respect a lot and asked them to give me some feedback on it.

And they were -- the questions, well, we don't have a lot to say on it. So I gave it somebody else and the answer came back basically the same. We really don't have a lot to say on this. It was hard for them to grapple with this. And I have a feeling it has to do with, you know, how it's structured.

You know, people ask, what do you want us to say? What do you want us to -- how are we supposed to deal with these assumptions? It's hard for us to pull out all of the assumptions and so forth, which kind of gets to my issue that I've been tinkering with was, you know, and this is just observations to help the product, the work product.

But I think there are things you could do to this report that would make it better for market participants for example, and hopefully for policy makers who are really going to be struggling with these issues. I think, you know, you really a chapter in something like this that says, you know, here is where we are today.

And if we don't -- and, you know, it's an infrastructural report. We don't invest in anything. This is what's going to happen and when it's going to happen we think based on load assumptions, you know. Just don't presume anything about infrastructure.

And tell policy makers, if we don't do anything this is what we think is going to happen and when. That's going to send a signal to policy makers and to people like me about, gee, we need to get off and we need to focus on that issue. We need to start resolving the infrastructure problems associated with what you're seeing as looming down the road, either, you know, two months, five years, ten years down the road.

Secondly, I think it would be helpful to include in a report like this all of your assumptions, just lay them out by DSM, by generation, by transmission or what, so that people can see them all in one spot and come to some sense about, gee, do all those assumptions make sense?

And when you integrate them and, you know, what's the interconnectedness between them? And it will make it easier for us to evaluate the connectedness between the assumptions that you've made, and maybe get at is there a problem in the assumption, and do a fail safe kind of review about these are reasonable and we don't see any problem there.

Third, I think it would be helpful in a report like this to include a time frame that says, you know, here's what we see. Here's a schedule of when the ISO was supposed to complete its market redesign. Here's a schedule when the PUC is supposed to do its transmission based on what we know today.

Is that adequate for what we're seeing from an infrastructure need prospective? Where are the disconnects on that? What's the likelihood they're going to be delayed further? As Commissioner Boyd pointed out, all these proceedings that are on a schedule that you see today, invariably they get delayed.

I mean we're working on issues at Tehachapi or whatever that have a high probability of being delayed. And what's the implication of that? And from the state perspective then we all can assess how important it is to raise issues at FERC, or at the PUC, or here at the legislature to solve these problems.

So and in that process you almost for policy makers certainly are creating kind of warning triggers on the time frame. We think of staff or as a Commission that if you don't make a decision by this point in time we are in jeopardy of having a problem.

We are raising the risk of a problem. And that will signal the people more effectively that a decision has to come down and win. I think that will be helpful for the planning process. Those are all my 40,000 foot observations.

PRESIDING MEMBER BOYD: I saw you turn your page back. Were you really done? Don't let

Al's comment chill you because this is the opportunity --

MR. KELLY: No, I think I'm pretty done. Al's comment didn't chill me.

PRESIDING MEMBER BOYD: We don't hear enough from the public in these, so this is your opportunity to let it all out.

MR. KELLY: I think one of the reasons that you don't hear more from the public, I don't think it's because their advocates are so great. I've gotten stabbed in the back a million times. I know that's not true. I think it's because people have a hard -- one, everybody is very busy, you know.

Within the last week and a half I must have gotten 400 page reports from this Commission, and three proposed decisions from the PUC of equal length that everybody is struggling with. So it's a time where everybody is very busy.

But secondly, I think for this particular report, like I say, I had two separate consultants take a look at this and say, all right, what do you want me to say? What should I say when I get up in front the (indiscernible).

And they really struggled with how to

guide me to make a presentation to you. And they didn't do a very good job because you can see I've (indiscernible) this morning. But anyway, this is a very difficult subject. And it was hard for the stake holders to I think get their hands around it.

CHAIRMAN KEESE: Let me interject an observation here because you are voicing a concern that impacts us greatly when we were talking with staff about scoping this hearing, this whole process, PR process. And had we, as a committee, chosen to decide where we're going with this, and then had staff back us up, it would have been much easier for this process, because we would have said this is the road we're going.

Give us the report that gets us there. We chose not to take that course. We gave staff a really difficult burden. We said we're not going to tell you where we're going. We want you to look at everything, baseline, projections. Bring it to us and then we will decide where we're going.

Now, I absolutely recognize that creates a problem for the public. But you have made some very strong points about this baseline that we have that will be helpful to us. The next step will be we'll tell you from this where we're going. And that's the point in which I think your consultants will say you're nuts, you know, about Tehachapi wind or whatever it is.

Commissioner Boyd and I, I will tell you, have struggled with how to do this. But we don't see any other way to build an open process on the first time we're doing a report that's going to carry on for years, and years and years.

We really can't make the assumptions holding up. So to the broadest as possible we want staff to lay everything out for us. And that's why I encouraged at the front end any recommendation you have will be considered.

If you can glean anything out of this, or if we can get other members of the audience to hit us a few times. Tell us what they think we should be doing. I appreciate what you've told us.

MR. KELLY: Well, I think it's very important that staff take that first step and just lay it all out, you're right. The piece that I don't see laid out right now is, you know, if we don't do anything where are we?

CHAIRMAN KEESE: I think that's a good point.

MR. KELLY: Because I think that first starting point is critical here. Every time you do one of these, this is where we are and, you know, we're fine or we're not fine based on that. And if we're not fine, this is what we've got to do. And then you start getting into the assumptions about, you know, is this plant going to come on in two years?

What's the likelihood of that going to happen in four years, or not?

CHAIRMAN KEESE: You know, you mentioned the disconnect between IOU and the muni actions on development. I think that's what we will glean out here when we say integrated policy report. We've got to figure out how to bring those aspects together. I'll tell you, at the end of the day the reasons the muni's are going forward is because they have the resources to build, which the others don't have.

Now, that skips your question of judgement about the future market. And I think you're right, the munis and others have been forced to take the risk themselves without a PUC guidance. And they have chosen generally to not go on the spot market for everything, to hedge one way or another.

And I think building generation is a very realistic hedge if you have the assets. And you can probably see that nobody else has funds. So look at a two or three year time frame to build power plants by the year 2006, 2007, we will be ahead of the curve. We will have built the plants and nobody else is.

MR. KELLY: But, you know, there's some language in here about the balance sheet of particular generation community. And in the procurements that have occurred over the last 12 months, 18 months, the few that have occurred, whenever they have occurred there's been -- the utilities, from my understanding, have been inundated with offers.

There is, particularly with the interim procurements that occur in the last quarter of 2002, not only did the renewable community, you know, swamp the resource need that was out there as defined by the utilities. But the thermal community responded as well.

The difference was in that context there was contract, and there was a commitment forward with the contract and get it in place. And even there were short-term contracts, you didn't see a lot of green fill development into that.

I think it was a signal that the real difference between the munis and the IOU's is that the muni's can bill it on their own balance sheet, or they'll do a contract. And that's not happening right now. I know the PUC is moving aggressively on that. And we're working with them on that.

And hopefully by the end of the year that will be all resolved. But while there are a limited number of independent power producers that have balance sheet problems, there is a number of companies that are moving forward. And their position to respond to these RFP's if and when they're let out.

So and my answer to that is, you know, regulatory certainty and, you know, a contract, which the staff have appropriately pointed out, are fundamental to making this work.

CHAIRMAN KEESE: And that's the integration --

MR. KELLY: Yeah.

CHAIRMAN KEESE: -- we're going to have to take here before this report comes out.

MS. GRIFFIN: Steve, I wanted to respond to one of your factual questions in your long --

MR. KELLY: Sure.

MS. GRIFFIN: Because it was addressed in a workshop last week. And that was on how confident are we in the DSM numbers. And we had a DSM workshop. And we're grilling the experts on that. They gave us a couple of key facts, one was that historically projections have been met plus or minus ten percent.

So in terms of, you know, when you go back and you look at we're going to X from program savings, and did they get it or not. Basically, you know, within a reasonable band they did. So we have one fact point that says in the past, when people have been estimating programs, they've been pretty good at it.

The second thing we said, okay, well, that's the past. Here's now. Are these -- do we have more or less potential because of all the saturations we're got so far, or new technologies, or harder to reach audiences. Because I don't know if you have seen the DSM potential studies are out there.

But everybody is using the same data. And it says that we could quadruple the amount of money that we put into PGC funds and still be investing in cost effective on a total resource cost basis. And, okay, guys, how confident are you in those numbers?

And what they've said was, we really are confident on the measure by measure number. But there's a big gap between measure by measure added up into programs you can actually deliver to consumers. And so they were not embracing (indiscernible) right at the moment.

They were saying, yes, we believe that the PGC investment, just at the amount of money that we have now, they felt very confident about the quality of their ability to deliver that. And that they felt pretty darn good. But maybe with a ten or 20 percent discount rate in a doubling of that amount of money.

But we're not at all confident or comfortable at going much beyond that. And we're saying, but that's not a decision we need to make today. The decision we need to make today is to restart and reinvigorate, and fix these DSM programs, and get it up to a certain level.

And then in two to three years we'll come back and look at the next increment. They certainly recognize that there's a lot of rebuilding of that DSM community that has to happen in the administration, get that straightened out.

That was why, I think, we were seeing a certain emphasis on let's get going in this way, but don't believe that we're committing now for all time.

MR. KELLY: Well, I mean it sounds like you're asking us to have the right questions of your consultants, whoever you're asking those questions of, you know. If you take that information when it gets into this report, you know, that it sounds, you know, committed.

You know, you're pretty confident that that level is going to be there. And that's important to know for me who does not attend the DSM meetings for example. But when I read a report it's helpful to know that, how firm that is.

PRESIDING MEMBER BOYD: Steve, you mentioned the stage I we had this year, which was a wake up call for a lot of people. I was particularly impacted because the previous day I participated in the big press conference at the ISO to appeal to everybody it's the start of the season, you know.

We have to think of conservation, etcetera, etcetera. And the very next day we get slapped with that. I said, well, great response by the public. But in really looking into it, it was, okay, May they tell me is the toughest month to predict mother nature, the weather.

And, you know, they blew it on the temperature. And there was, you know, probably 15,000 megawatts of energy available in terms of economic off line, etcetera, etcetera. So that gave some feeling of security that, well, this isn't a precursor to 2001 all over again.

But I agree with you, I mean you've got to check all these signals, and there aren't guarantees that if we have a western heat storm again or something, that California megawatts are running across the board or somewhere else.

That is a dilemma. But we feel pretty -- you know, we feel very good about this year, and the next couple of years. It's the uncertainty of the future and a lot of the points that were made about economic recoveries in other places other than California impacting the whole system.

But the glacial alacrity which with this system responds to fixing our future is of a concern to a lot of folks. I think the concern is reflected in the energy action plan, and desires three agencies to try to grab the bull by the horns, at least to some degree, and more aggressively move out in this world, which, you know, accelerates any given day in terms of how you react to it.

But your points are good points. And to your credit, I took more notes than I have in a long time. And I appreciate your input because this is a workshop, and it's supposed to be fairly informal. And it really is an opportunity for people, albeit polite, to challenge people's assumptions if they can dice them out.

I heard that message. And we welcome, and I welcome for the staff because I'm sure they welcome too, inputs. Because, you know, we want to be more right than wrong when we finish this thing. And the only way we're going to know that if you test and retest things.

So tell your consultants to sharpen their pencils and keep digging.

MR. KELLY: I will.

MR. ALVARADO: Maybe even out of that, Steve, heads up to you and your consultants, we do plan on releasing a draft, electricity natural gas report, for the end of July where we're going to try to knit together a lot of the assumptions and some of the findings of our studies.

MR. KELLY: Okay. That will be great. I look forward to it. Thank you.

PRESIDING MEMBER BOYD: Al, I'm going to suggest that you ask for a show of hands of how many people are going to come up and testify in this now open public testimony period that is scheduled to run after the lunch break all the way to the end of the day.

If we don't have a lot of folks who have something to say, we must as well press on. If we're going to have a lot of people then we can feed them all so to speak.

MR. ALVARADO: Okay. Please. Well, it looks like we just have two speakers. So I suggest we maybe carry on.

PRESIDING MEMBER BOYD: Keep going.

MR. ARTHUR: My name is Dave Arthur. I'm with the City of Redding. I'm a resource planner there. Which just to give you a background, involves long-term arrangements for gas, fuel for our power plants, long-term power contracts, relationships with the California ISO and FERC matters.

So it covers a broad spectrum, and so while I probably don't know a great deal about anything, I get to see an overview of a lot of things. First of all, I would like to say I think the reports, and actually the gas report that we'll talk about tomorrow, are both extremely well done.

They're very helpful to me in the sense that in one place you can start to see a lot of information presented. And the upside of that is that you can begin to see whether the pieces seem to fit together or not in a way that is impossible, if that isn't correlated in a coherent understandable manner.

The downside I guess is that as you start to see all of the pieces come out you can begin to start to ask questions as to whether the different directions we're going seem to make sense, or whether because most of us live in what I would characterize as a more cartesian world we each have our own little part.

We optimize there, but we don't necessarily see the linkage to other sorts of things. And so some of my comments are going to be directed to what I see at least some potential issues that come out in getting to see all of this information in a single place.

It seems to me that one of the things that we've learned, and in fact in the different arenas that we spend enormous time sharing differences of opinion around, has to do with the fact that generation and transmission, and load centers are intricately linked.

And even though we have, as a state, chosen to treat them as separate for reasons that those of us in the municipal world still do not understand, we accept the fact that that is the policy of the state.

And so I want to make a couple observations as it relates to the fact that they are linked even though we tend to formulate policy as if they were not.

It seems to me that one of the things that is coming out of the work that the ISO has done, and the work that's being presented here, is that location is more important than ever. That is to say that where generation is actually located can be almost as important as how much of it that you have.

And what we saw today is that we seem to have a sufficient quantity. It's not entirely clear we have it in the right places. And correlated to that is we start to talk about transmission enhancements. And it seems to me that one of the distinctions that was drawn was between something that was called a reliability improvement, or an upgrade, and an economic improvement or upgrade.

And I have to confess, the first time I heard the distinction was probably two or three years ago. And it was at the CAL ISO, and it was when they were wrestling with some of these same questions. And Kellan made some what I can only characterize as brilliant presentations in which he took extraordinarily complex matters and distilled it down to those of us without a transmission background to being to understand what he was talking about.

But at the end of the day I think it became clearer and clearer that drawing a distinction between economic and reliable transmission may have resulted in some serious misunderstandings. And may have led us in some very faulty directions as it related to how much transmission we need.

Because at the end of the day it may be much more important to ask the question is state policy going to be focused on a return to a more cost based type arrangements, or are we going to actually try and move forward with a market based approach?

And I think that even the market surveillance committee has acknowledged, certainly with reluctance, but they have acknowledged that you probably need more infrastructure, and a different kind of infrastructure if you want to facilitate and enhance competitiveness then what you need if you want to remain cost based, sort of like in the old world.

And so it seems to me a more productive, or at least in addition, could be say if we move forward with an effort to have workable markets, where do we need additional transmission in order to have sufficient infrastructure so that those markets have a reasonable prospect of working?

And I think that will lead to some very different conclusions. For example, and I'm working from my recollection here, I may slightly misspeak and hopefully Robert will correct me if I do. But my recollection is in the most recent MDO2 draft it's pointed out that there is confidence only that there's really strong workable competition most of the time between SP15 and NP15.

And that in many other areas significant quantities of what we lovingly call on the ISO world mitigation will be required in order to provide adequate price protection for the consumers. Well, that suggests that we need quite a bit of transmission, if it is to be the state policy to move forward with more competitive markets.

So I throw that out as you think about an integrated plan, an integrated plan for which type of environment. A second is that we've talked about, and it was interesting to see, that if we are successful in more a renewable program that we wouldn't develop nearly as much gas fire generation.

Now, without endorsing gas fire generation or condemning it, I will point out that it's very flexible as to where you can locate it. And if renewables on the other hand are much less flexible as where you can locate them, they seem to have preferences.

So one seems to get located where wind blows, and the sun seems to get located, at least in most instances, where the sun shines a lot. And so if we move toward more renewables that will probably turn out to have a profound impact on where generation is built, which will turn around and have a significant implication where the amount, and type and quantity of transmission that we have or need.

And for example, in the NDO2 implicit in that is a desire to put out price signals as to where generation is needed. Now, the presumption there is that generation is flexible with respect to where it's located. If it turns out that our policy is to have a type of generation that isn't very flexible in terms of its location, then to have adopted a pricing policy for transmission allocation that's predicated on flexible generation location, creates some pretty serious policy gaps potentially.

And we could see that we have unintended and less pleasant outcomes surrounding that type of thing. And then the last point I want to make, having to do with these inter-relationships, it was really interesting, I've been two national gas conferences in the last three weeks, four weeks, and in each of those there is a profound confidence that we will heavily on L&G.

And there was a profound pessimism as it related to the supply and demand characteristics if we don't get L&G. It is the view at least of those in the gas industry that at least one, possibly two, but at least one major facility will probably be built in Baja, California.

And that will have profound implications for the sighting of additional generation. And it will, therefore, have profound implications on the need for the associated transmission. And it may or may not have profound implications on the type of generation we've actually come to rely upon in the future as well.

And so I'm sure that tomorrow we'll talk much more about this, but, again, it just simply brings out the fact that policy decisions being made in one arena will turn out to have a very significant impact on the policy decisions we need to make in other arenas.

And to close, three or four times this morning I've heard reference to we might have a little excess capacity. That seems to me to actually be one area where I think this body could be extremely helpful to the people of California. And that is to explicitly address the question is having a little too much a much greater or a much smaller error than having too little.

And it seems to me that that's an extraordinarily important question because all of us that have ever had to forecast know we will be wrong. But we can bias the direction so that when we're wrong it either probably results in too little or too much.

And we probably ought to error, at least based on what our judgment is, as to where the more profound error is. I think I should comment briefly simply on the discussion that went on with the previous speaker as to why municipals seem to be following behaviors that are different than the

IOU's.

And I actually use to work for an IOU. So I actually know a little bit about their decision process as well. But I don't think that the munis are doing anything particularly unusual. We start with a very simple premise. Our goal is to minimize the long-term cost for our consumers, to do so without imprudent risks, and to ensure reasonable reliability.

We do differ from some that we think we have to start with our customer's preferences. And in that respect, they have told us that they want to have power pretty much on demand without enormous variances in price by the time in which they use it.

So we go out and we attempt to build a system that is tailored to respond to that set of priorities. We feel that we should have a diversified portfolio. So for example, we do in fact buy long-term contracts from the market. For the most part we're glad to do so.

We've discovered is that it's hard to retain one of those. The City of Redding had one contract turned over at least once with some prospect of it turning over again is the vendors seem to keep withdrawing from the market. On the gas side, we've attempted to, again, reduce volatility.

We've become, for example, a shipper all the way to Peco to ensure that we have a physical supply of gas that will always be available around a plant. We've done a number of forward market purchases in the gas markets to try and minimize the volatility, because volatility is something that gives problems to our customers.

They don't want the -- certainly other types of customers may very well accept that volatility, and that's an individual customer choice. But we have found is that we are just doing the basics. Now, what I've tried to explain here, that doesn't get us into really being vertically integrated or not.

It simply says we've got an obligation to customers. We've gone out and tried in the forward markets to create a diverse supply and hedge the volitilities where we think it's appropriate. And I think too often we surround ourselves with ideological emotions over some of these terms rather than simply getting back to the basic, which is we should all be here to try and keep the prices down, the reliability up, and we should use the various techniques available to us, which can include competitive markets.

They can include spot markets. It can include building. There isn't one that's right and one that's wrong. In fact, what we've found is that there's a place for all of them that were better off if we had all of them rather than if we spend too much time arguing that there should only be one, or there should only be the other.

That seems to limit choice. And the goal is to expand choice. And when we've expanded choice we've always come out with a better outcome. Thank you.

PRESIDING MEMBER BOYD: Thank you.

CHAIRMAN KEESE: Thank you.

MS. BACHRACH: Good afternoon. My name is Devra Bachrach. I'm here on behalf of the Natural Resources Defense Council. I promise I'll keep it short because I know everyone wants to get some lunch. Thank you for the opportunity to provide comments today on the staff report.

And I'd like to first start by commending the staff for the considerable effort that's gone into creating this draft report. And

I'd like to commend the Commission for all of the effort going into the entire Integrated Energy Policy Report process.

My comments today will focus on how the staff report incorporates energy efficiency into the demand forecast in the assumptions related to energy efficiency. Overall, the staff reports assumptions related to energy efficiency have improved considerably since the drafts that were issued in February.

So I'll highlight some of these improvements, and I also have several suggestions on how to revise the DSM scenarios to more realistically represent the current state of California's electricity industry. So let me begin by commending the Commission for the improvements in the staff reports since the February draft.

And I'll highlight two important improvements, first the staff report now incorporates energy efficiency into the demand forecast, where as the initial forecast did not. This is obviously an important improvement.

And second, the staff report incorporates the effect of energy efficiency in the demand forecast rather than placing it on with the supply side of the picture. This is important because the demand forecast are used as inputs to many other parts of the IEPR report.

And so excluding the energy efficiency impacts from the demand forecast could askew the results of other parts of the IEPR, such as the transmission infrastructure plan, or the natural gas infrastructure plan. So the forecast has improved.

We think that there's some additional room for improvements. First, to make the baseline demand forecast as close to reality as possible, it should include both the minimum level of PGC investments required by law, and the utilities plans for additional investments in energy efficiency.

The best information that we have right now about how much California will invest in energy efficiency going forward is contained in the long-term procurement plans that the utilities filed at the Public Utilities Commission on April 15th.

This information should be included in the CEC baseline demand forecast since it's the best state of our knowledge right now. The procurement plans that the utilities filed show that they plan to increase investments in energy efficiency by nearly two-thirds, thereby nearly doubling he energy savings relative to just having the PGC fund the programs.

So if the CEC were to omit the utilities plan from the demand forecast, it would almost guarantee from the start that the baseline forecast would be incorrect going forward. We also suggest that Commission revise the DSM scenario so that they expand the range from at the low end, the minimal level of investments and energy efficiency required by law, which is the PGC fund investments.

And that the high end acquiring all cost effective energy efficiency, which is California policy. Now, you pointed out that one of the goals of this report is to identify key uncertainties.

And I think that the main uncertain variable when it comes to energy efficiency investments is how much the utilities, or how the utilities will respond to the PUC's directive for them to consider all investment -- all cost effective energy efficiency investments.

So for the Commission's scenarios it would be most logical to this variable as the uncertain variable, varying it from, you know, n o additional procurement investments, meaning just the energy efficiency investments requirement by law at the low end, to procuring all of the cost effective resources at the high end.

This proposal that we're making to you would alleviate some of the problems that we see with the current scenarios that are included in the report. Let me start just by reminding you what the current scenarios are. At the low end, the report assumes absolutely no investment in energy efficiency going forward. That the law would be changed so that there would not be a PGC requirement.

For the baseline, the report assumes that only the PGC fund investments are made, and at the high end the report assumes that the PGC fund would double the investments made in energy efficiency.

And these scenarios are not very realistic. The low DSM scenario in which absolutely no investments in energy efficiency are made going forward is highly unlikely, first because of the PGC funds are required by law.

It would require a law change. It's also an unnecessary scenario I think because this scenario could be understood just by simply identifying clearly how much of the baseline scenario is assumed to come from energy efficiency, but could then be inferred from.

The high DSM scenario as its currently included in the staff report is right now only slightly more aggressive than what the utilities themselves are planning to do. And, therefore, it's probably closer to reality right now than the staff reports current baseline forecast.

So to make the full range of the scenarios more realistic we think that on the low end, for the low DSM scenario, it should include only the PGC fund investments that are required by law for the baseline to include both the investments required by law, and what the utilities plan to do through their procurement panning process.

And at the high end to include investment and all cost effective energy efficiency consistent with California policy. And

I realize that staff might have more work to do to try to define what would constitute all cost effective energy efficiency.

But I think that would be a better range for the Commission to look at to vary between these ends of the spectrum. Finally, I also wanted to urge the Commission to explicitly denote in the next version of this report what assumptions are being made about the savings that will come from the Energy Commission's energy efficiency standards.

As you know these standards result in very significant energy savings. So the forecast should delineate the amount of savings that are soon to come from the past both building and appliance standards, and the anticipated effect of the 2005 update of the building standards that's currently underway, and the recently initiated proceeding to update the appliance standards.

So that concludes my comments. Thanks again for your time, and for considering NRDC's comments.

CHAIRMAN KEESE: Thank you.

PRESIDING MEMBER BOYD: Thank you.

MR. ALVARADO: Do we have any other

comments or questions while we have the opportunity of our staff up here? It looks like -- unless, David or Judy, do you have anything else to sort of clarify any of the assumptions you used, BLT hold the mayo?

The only other thing I'd like to add, I probably should have said this earlier, is we're still open to receiving any comments based on either the discussion we had today or if anyone else now has an opportunity to read the reports and can see it with a different light.

If you do have any comments please file them by June 20th, the sooner the better. Because we are at this point starting to write the electricity and natural gas report, which I indicated we do plan on releasing towards late July.

With that being said, I just want to remind the folks that tomorrow we will be discussing the staff's natural gas market outlook report. Actually, market assessment report, which sort of carries forward some of the findings that we have, the electricity scenario analysis.

But tomorrow we'll discuss (indiscernible) implications to the natural gas system. With that being said, I propose we adjourn this workshop.

PRESIDING MEMBER BOYD: Thanks, everybody, for your comments, I appreciate it.

(Thereupon, at 12:35 p.m., the Committee Conference was adjourned.)

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CERTIFICATE OF REPORTER

I, ALAN MEADE, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Conference; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 19th day of June, 2003.

ALAN MEADE